Investor-Owned Utility Resource Plan Summary Assessment

Energy Commission Staff Report

Prepared for the *2005 Energy Report*

Committee Hearing

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Call-in Number: 888-857-6266
Call Leader: Al Alvarado
Passcode: Electricity

Supply Forms Format

- Monthly capacity and energy resource accounting tables for 2006-2016
  - Compare expected demand with existing and planned supply to identify resource gap
  - Assign resource gap to generic categories of resources: plausible RPS-eligible renewables, baseload, load-following and peaking, year-round load-following, seasonal peaking
- Many uncertainties affect estimates of what the gap might be and how much procurement to authorize in advance
  - How well existing policies are implemented
  - What new policies, decisions will be affecting IOU demand and procurement
  - Natural gas and electricity market conditions
- Future resources actually procured will differ from these resource “plans”
  - Bids received in solicitations are evaluated on their merits, using least-cost best-fit criteria

F&I-Specified Supply Scenarios

- **Reference Case Assumptions**
  - D.04-09-060 energy efficiency goals are met
  - Price-sensitive demand response goals reduce peak load by 5% after 2006
  - RPS-eligible renewables are 20% of retail sales by 2010
  - No new load migration to Direct Access
  - Some load departs to Community Choice Aggregation or Municipalization
    - begins no earlier than 2007 but no later than 2013
    - at least 4% but no more than 10% of bundled load
- **Reference Case w/o New Transmission**
  - Additional case required if Reference Case assumed major new transmission
- **Accelerated Renewables Case**
  - RPS-eligible renewable development on path to 33% of retail sales by 2020
    - PG&E and SDG&E: 28% by 2016
    - SCE: 31% by 2016
- **Core/Non-Core Scenario** – a "low load" case
  - by 2012, 75% of customers with peak demand of 500 kV or more depart
- **Preferred Case** - IOUs free to use own assumptions

Additional F&I Requirements

- Resource Plan Costs
- Local Reliability Assessment
- Impact of GHG Adder on Bid Evaluations
- Natural Gas and Wholesale Power Prices
  - How variations in these affect resource plan costs
- Impact of QF Contract Persistence
- Additional Uncertainties
  - Nuclear unit prolonged outage or retirement
  - Mohave Generating Station return to service
- Transmission Constraints to Procurement

Organization of Staff Assessment

- Scope limited to PG&E, SCE and SDG&E
  - Other LSEs included in July 11th statewide outlook
- Preferred resource procurement mandates
  - Energy efficiency
  - Price-sensitive demand response
  - RPS-eligible renewable energy
- Distributed generation
- Existing & planned resources
  - CDWR & QF Contracts
- Net Open Position
  - Qualitative description only
- Resource Plan Impacts and Uncertainties
- Transmission Constraints

Energy Efficiency Mandate

- Individual annual kWh, kW, and therm goals for each IOU for period 2004-2013
- Goals based on remaining potential for cost-effective and achievable programmatic savings – 30,000 GWh estimate
- Goals target 50-59% of IOU incremental electricity demand over 2004-2013
- Considered “aggressive, stretch goals”

Findings from EE Assessment

- Short-term goals (2006-2008) should be met by all IOUs; nearly $2 billion in PGC and procurement funding for EE
- SDG&E's resource plan incorporates a lag factor, but meets the goals
- PG&E incorporates a lag factor and meets the goals when their internal assumptions about baseline program savings are used instead of staff's
- SCE believes the post-2008 goals are not credible, and files an Alternate Case that is lower by about 300 MW and 1,500 GWh in 2013

IOU Efficiency Uncertainties

- New 2005 potential study could increase or decrease the long-term efficiency goals, given changes in cost-effectiveness, equipment saturations, standards, or emerging technologies
- Changes in counting conventions could skew programs toward short-term rather than longer-term, more innovative projects
- Corrections to previously overstated savings values and rising free ridership may make achieving goals more difficult; ramping up expenditures may be difficult
- 2013 savings depend on expanding customer base, developing innovative program strategies that lead to continued savings in the later years, and incorporating emerging technologies

Price-Sensitive Demand Response Goals Serve Two Purposes

- To create an incentive for the regulated utilities to develop demand response resources (D.03-06-032)

- To provide a benchmark for the amount of reliable demand response resources that utilities are required to procure (D.04-12-048)

Demand Response Goals

Table 3-1
Price-Sensitive Demand Response Goals[1]

Year	PG&E	Edison	SDG&E
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2004 (revised)	343 MW	141 MW	47 MW
2005[2]	450 MW	628 MW	125 MW
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

[1] The goals were to be achieved by July 1st of each year. Goals for 2004 were revised in an Assigned Commissioner's Ruling dated June 2, 2004.
[2] 2005 goals were originally described as 3 percent of annual system peak, but in D.04-12-048 were converted to numeric goals for each IOU, p. 60

Three Ways to Count DR MW In Resource Procurement

- Enrolled MW
  - Reflects the maximum possible demand response available from customers enrolled in existing programs
- Demonstrated MW
  - Not yet reliable; not enough historical data or program experience; small current enrollment
- Expected MW
  - Combination of demonstrated and best conservative estimate of program managers and resource planners

Current Voluntary Demand Response Offerings Will Not Achieve the CPUC's DR Goals

- **Goals were developed with the expectation that all customers would have the opportunity to contribute toward the demand response goals.** Currently, only large customers (over 200 kW)—about 40 percent of system load—have interval meters and thus the ability to participate.

- **Most large customers have already adapted their operations to minimize on-peak consumption in response to existing TOU rates and peak demand charges** and many of the largest customers already participate in existing reliability programs, which preclude participation in the current price responsive programs.

- **The programs and tariffs available to large customers are constrained** by the requirements that participation be voluntary and that they be class revenue neutral. These constraints result in program designs that yield only small benefits to participating customers, so the incentive to participate is small, even for customers with advantageous load shapes.

- Larger **customers with significant air conditioning load** (as opposed to process load) **face significant expense and effort to develop load management strategies** compatible with their existing constraints.

- **Program stability is a concern for customers.**

- **Smaller customers do not necessarily have the expertise on staff and find load management to be outside their "core business."** Thus even if there are potential savings available, it is not necessarily the case that these customers will take the time to learn about, then act on, the possibility.

DR Uncertainty in Procurement

- Expected MW should be counted when assessing residual need for procurement

- The current confusion should be resolved between what is allowed to count toward DR goals set in D.03-06-032 and what is used to determine the level of residual procurement to authorize

Renewable Portfolio Standard (RPS)

- F&I identified general RPS program goals
  - Reference Cases
    - 20% of retail energy sales from RPS-eligible renewables by 2010
  - Accelerated Renewables Scenarios –
    - 28% by 2016 for PG&E and SDG&E
    - 31% by 2016 for SCE
- Staff developed IOU-specific annual procurement target (APT) "attainment paths" as a benchmark
  - Verified IOUs' assumptions about Existing and Planned (project ID, output, eligibility)
  - Found plausible the IOUs' assumptions about availability of generic new renewables (i.e., within estimates of technical potential)

IOUs' RPS Plans

- SCE could meet both the 20% by 2010 and 31% by 2016 APTs with in-service area eligible renewables
- PG&E could meet the 20% by 2010 APTs with in-service area (NP15) renewables
  - Requires $170-$230 Million transmission costs (not including interconnections)
  - To meet 28% by 2016 APTs, PG&E would go outside NP 15 for best-fit renewables (incremental transmission needs not identified)
- SDG&E cannot meet the 20% by 2010 APTs without new major transmission line and reliance on renewables imported from out of its service area
  - Has not analyzed if its 28% by 2016 scenario is achievable

Identified RPS Procurement Issues

- Above-market RPS compliance costs and their rate impacts are not sufficiently understood:
  - **Contract price of renewable power** - if retailer's obligations are increased, accelerated, or made widespread; if marginal resources are less productive; if higher cost technologies are required to comply
  - **Cost of new transmission and interconnections or upgrades** - if remote renewables are required to comply
  - **Direct non-transmission system integration costs** - if new operating infrastructure is required for real-time absorption of increasing amounts intermittent and must-take energy
  - **Indirect integration costs** - if firming capacity required; if renewables' intermittence increases volatility of retailers' wholesale power market purchases (if caught short) and sales (if long)
- Whether PGC funds are adequate to pay the above-market component of the contract price for renewable energy creates some uncertainty whether the RPS program goals will be met

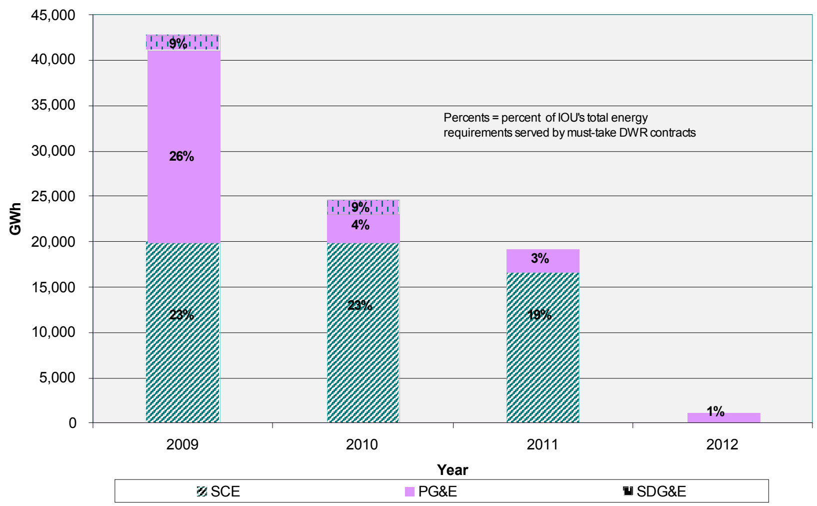
Additional Identified RPS Issues

- Deliverability from outside service area to load centers is a constraint on RPS compliance, requiring successful licensing of upgrades or new transmission and interconnection projects
- System reliability and operational consequences of increasing levels of intermittent and non-dispatchable renewable energy obligations aren't understood
- Allowing unbundled RECs for RPS compliance would be more efficient, environmentally beneficial and less expensive (if rules governing REC purchases facilitated RPS goals)
- Existing RPS targets should not be increased until the progress of all LSEs towards meeting the goals has been analyzed in detail

Distributed Generation Role in Procurement

- California has no mandate for DG resources—no express capacity or energy goals
- IEPR, EAP, various legislation specify preference for DG over traditional central power plants, transmission and distribution
- Supply forms requested dependable capacity and energy IOUs expect in forecasts
- IOUs do not provide sufficient information in their filings with respect to assumptions on:
  - Definition of DG
  - Types of DG included (e.g., renewable, nonrenewable)
  - Application of DG technologies
- Staff can not determine feasibility of IOU forecasts without these details
- Since relative DG amounts are small, the uncertainty this imposes on residual procurement estimates is small

Existing & Planned Resources
DWR and QF Contracts



Source: IOU Public Form S-2

- DWR contracts provide large amounts of both must-take & dispatchable energy & capacity
- IOUs resource profiles and procurement needs will shift considerably as DWR contracts expire
  - more shaped to meet portfolio needs
  - conform to resource adequacy and deliverability requirements
- IOUs' resource cases assumed only 10% or less of resources currently under QF contracts need to be replaced in procurement

IOUs' Net Open Positions

- Renewable and non-renewable generic resource additions identified by the IOUs in their S-1 & S-2 forms are not disclosable
- IOUs are generally "long" in energy for most hours over the next few years
  - As CDWR contracts come to an end in 2010-2012, the IOUs will have a major shift in their energy needs, as CDWR contracts account for roughly one-fifth of total energy requirements
  - Some replacement will be met by energy efficiency program savings, the goals for which fill approximately 50 – 59 percent of incremental demand
  - Combining energy efficiency, energy-rich renewables and demand response, leaves a relatively small role for new base load generation
  - IOUs have needs throughout the forecast period for short-term, mid-term and long-term dispatchable and shapeable capacity
- Since fossil resources are the 'resource of last resort', the IOUs must have contingency plans should energy efficiency, DR and renewable programs exceed or miss their target levels

Resource Plans Cost Estimates

- IOUs' resource plan cost estimates are not useful for quantifying and comparing scenario cost impacts
  - Categories of significant costs that would be expected to change across scenarios were omitted (due to lack of information or time)
  - Some costs that would be expected to be different across scenarios were simply assumed to be the same
  - Not enough information was provided to verify cost estimates
  - IOUs caution Energy Commission's reliance on the cost estimates
- IOUs' narratives are useful for qualitatively identifying potential cost issues that need to be better understood (e.g., see RPS Issues, slide 15)

Local Area Reliability Assessment

- IOUs say it is CA ISO’s not LSEs’ obligation to meet local area reliability requirements
  - LAR resources (i.e., under RMR contracts) are dispatched for needs of grid, not to optimize an individual LSE’s portfolio
  - LSEs individually cannot know the type, location or amount of required future LAR resources
  - IOU resource cases rely on latest CA ISO short-term studies or use rules of thumb in their portfolio planning to include “generic placeholders” for future units that would meet LAR requirements
- SDG&E: Reduce RMR costs, not RMR units
  - Don’t require IOU to add resources beyond its portfolio need to eliminate RMR units
  - Cost of meeting LAR requirements should be borne by all who benefit

Impact of GHG Adder on Bid Evaluations

- PG&E uses “tipping point” analysis to determine if a GHG adder makes a difference
- SCE’s method gives an emission benefit to bids that would decrease greenhouse gas emissions relative to emissions from an assumed “supply stack”
- SDG&E recommends the method should:
  - “achieve the desired benefits with little or no distortion in the outcome”
  - have a time dimension so the value of reducing CO_2 is the same regardless of when the reduction occurs
  - “include some discount to the GHG adder to account for the non-availability of a particular type of resource [bid] because during those periods (particularly peak periods) there may not be a reduction in GHG emissions”
- Because of significant differences across the IOUs and the lack of detail provided, the pros and cons of each approach aren’t understood

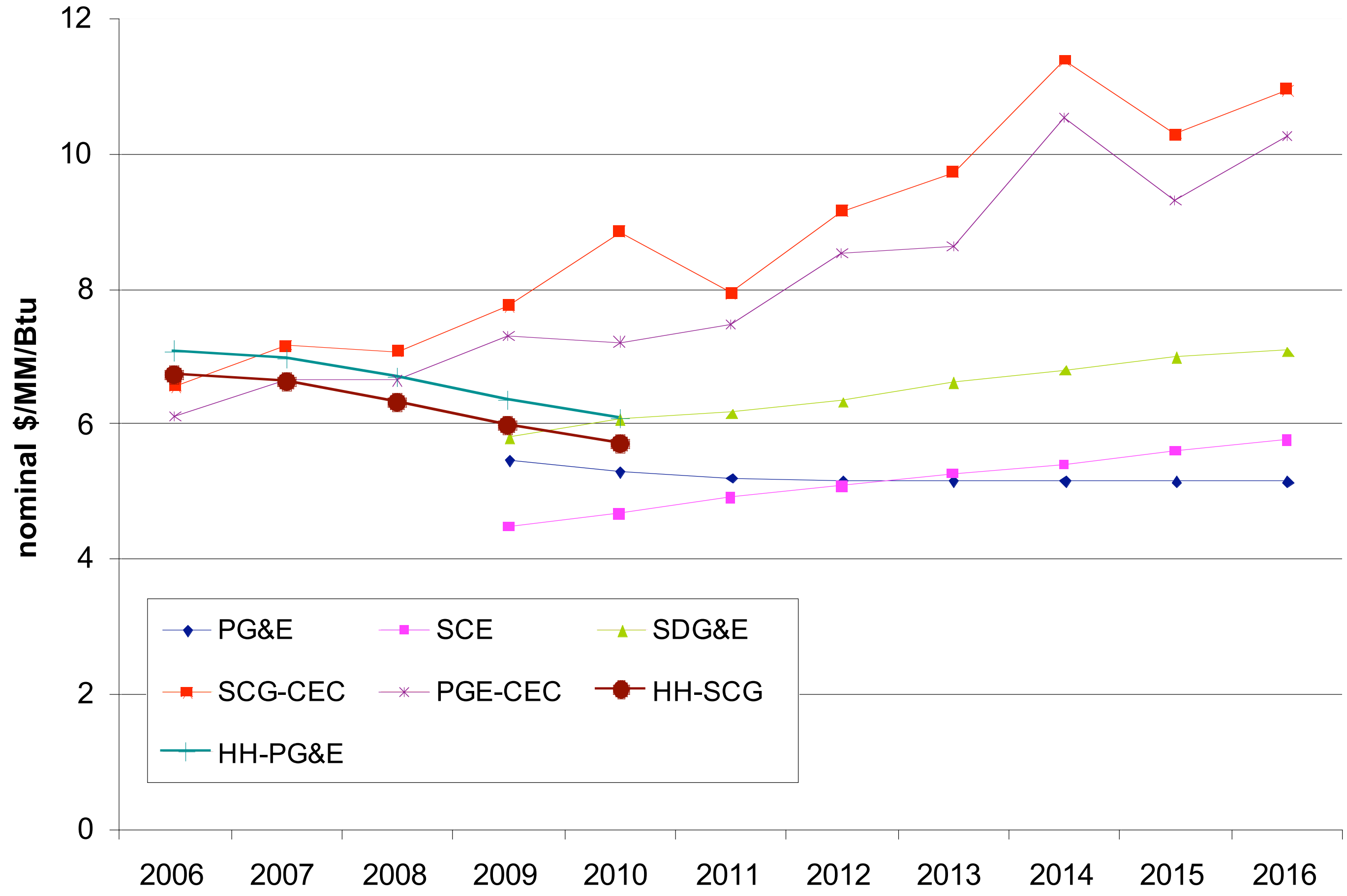
Natural Gas Price Forecasts

- IOUs' forecasts for 2009 – 2016 are public, while earlier information is confidential
- IOUs also provided a high and a low price forecast to bound the reference case prices
- Many ways to forecast natural gas prices
  - NYMEX Futures
  - Fundamental market analysis (simulation models)
  - Time series, projections based on historical trends

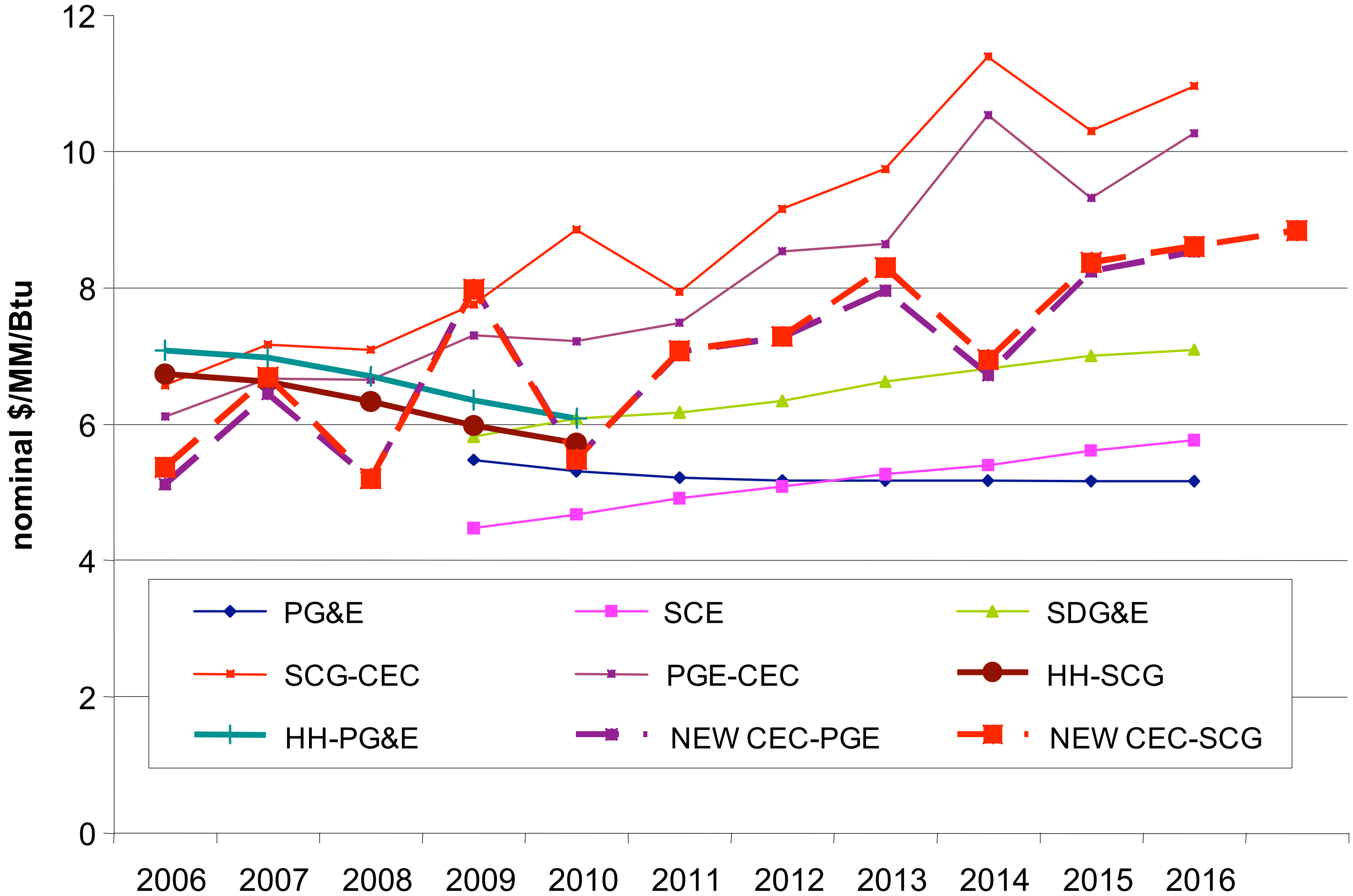
Reasonableness of IOUs’ NG Prices

- NYMEX quotes are good indicators for near-term prices
  - IOUs all used the NYMEX futures prices for early years
  - Differences across IOUs use of NYMEX quotes
    - Vintage of quote
    - Single or multiple point quotes
- But NYMEX quotes are a continuously changing price expectation, so are challenging to incorporate into longer-term price forecasts
- Overall methods used by IOUs are reasonable, but results widely vary
- PG&E, with its extrapolation methodology, is the only IOU with a declining NG price forecast throughout the period.
  - All others show increasing prices by end of horizon

Comparing IOUs' NG Price Forecasts to Later Vintage NYMEX Quotes and to Preliminary Staff Fundamentals Forecast



Comparing to New Commission Staff Forecast



Wholesale Electricity Prices

- Electricity price assumptions driven by gas price assumptions
- Staff assessed electricity price forecasts by backing out IOU gas price assumptions and using staff assumptions
- Overall, the IOUs' electricity price forecasts methods are reasonable, given each IOU's assumed natural gas price input assumptions
- Since PG&E's forecast of natural gas prices declines over time, so does its electricity price forecast
  - This leaves PG&E's forecast in the anomalous position of declining over time while all of the rest increase over time.

Nuclear Unit Early Retirement

- SCE and SDG&E's responses are plausible and consistent with SCE's application filed at CPUC
- If SONGS Units 2 & 3 retired:
  - Southern CA would lose 2,150 MW
  - Much of the replacement capacity would have to be in-basin to satisfy local reliability and maintain import capability
  - If replacement is gas-fired, higher gas demand results
  - Transmission grid upgrades, potentially including new 500kV transmission lines and static VAR Compensators (SVC), could be needed to mitigate "transmission line overloading, low voltage situations, and system instability that in turn could cause local blackouts and other service reductions"
- PG&E made no filing regarding Diablo Canyon

Mohave Return to Service

- SCE's description of the impact on its portfolio of returning Mohave Generating Station to service after refurbishment:
  - Reduces SCE's resource gap by approximately 884 MW
  - Displaces an equivalent amount of baseload, intermediate, or peaking capacity (depending on the least-cost best-fit of resource types)
  - Energy displacement will be at a high capacity factor given Mohave would be dispatched at relatively low variable costs
    - Mohave's fuel supply is provided under a long-term contract with much of the associated fuel costs being fixed, resulting in low marginal costs to dispatch the facility
  - Mohave's fixed costs, including fixed operating costs and capital costs could potentially displace the capacity payments associated with any generic resources that Mohave replaces
- More detail in record of CPUC proceeding (A.02-05-046)

Uncertainty of Core/Non-Core Departing Load

- F&I directed IOUs to file “low load” case: by 2012, 75% of customers with peak demand of 500 kV or more depart
- SCE and SDG&E did not file low load cases
  - SDG&E did file an estimate of departing load, but only a narrative description of how its portfolio might be affected
    - Would not reduce overall need for in-basin resources or transmission to meet grid reliability needs
    - Adjust procurement decisions to minimize stranded costs
    - Could have “excessively high” reserve margins
- PG&E did file a Core/Non-core Case
  - PG&E’s Reference, Preferred, and Core/Non-core cases assumed existing levels of direct access, 50% and 75% (of >500 kV) load departs, respectively
  - To minimize potential stranded costs resulting from loss of load, PG&E’s portfolio will include long-term, mid-term and short-term resources, which can be adjusted in response to changing requirements

Departing Load Identified Issues

- SCE lacks information for a "reasoned estimate" of departing load and cautions that speculative departing load assumptions can increase portfolio risk if used to establish procurement limits
- SDG&E identifies issues that must be resolved--demand threshold, ability to aggregate load, timing of implementation, and switching and notification rules-- before it can:
  - Develop a good estimate of potential departing load
  - Estimate resource requirements under those assumptions, and
  - Identify what obligations the utility must plan for in order to fulfill its obligation of "provider of last resort," should the departing load return

PG&E Transmission

- PG&E included in all scenarios all transmission facilities contained in its most recent CA ISO-approved grid expansion plan

- Although not identifying them specifically, PG&E says that transmission costs of about $170-$230 Million (not counting interconnection costs) would be needed to meet an RPS obligation of 20% by 2010

- Additional transmission and interconnection costs and/or REC costs would be needed to attain 28% by 2016.

SCE Transmission

- SCE's Reference Case includes the Devers – Palo Verde #2 500 kV line
  - SCE has filed an application with the CPUC for a Certificate of Public Convenience and Necessity (CPCN)
  - Los Angeles Department of Water and Power has filed a protest, indicating their intent to exercise a contractual right to construct the project

- SCE's resource plans do not assume any incremental new long-term generating capacity resources over the DPV2

- SCE recommends the Energy Commission ignore the DPV2 resource plan costs as incomplete, and instead consider the more comprehensive CA ISO analysis SCE submitted with its CPCN

- SCE notes that "accelerated renewables" development poses transmission and system operation challenges

- DPV2 and renewables-related transmission projects will be assessed in staff's report, *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*.

SDG&E Transmission

- SDG&E's Reference Case included a new 500 kV bulk power transmission project
- Based on its current RFO information, SDG&E claims it would not be able to meet its RPS 20% by 2001 goal without the 500 kV project
- SDG&E also claims that to meet its area load without new transmission will require local generation, which could be constrained by limited availability of offsets for air pollutant emissions
- Not enough information to validate either claim was provided in SDG&E's Supply or Transmission forms